AR72

Winspear Business Reference Library
University of Alberta
1-18 Business Building
Edmonton, Alberta T6G 2R6

2003
ANNUAL REPORT

PETRO-REEF RESOURCES LTD.
2020, 800 5th Avenue SW
Calgary, Alberta T2P 3T6
Canada
Tel: (403) 265-6444
Fax: (403) 264-1348
petroreef@shawcable.com

Digitized by the Internet Archive
in 2024 with funding from
University of Alberta Library

https://archive.org/details/Petr4023_2003

PETRO-REEF RESOURCES LTD.

ANNUAL REPORT 2003

Contents:	**Page**
Highlights	2
President's Message and Review of Activity	3
Reserves Report	5
Management's Discussion and Analysis	25
Financial Statements with Notes	35
Three Year Review	49
Corporate Information	50

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
Bbl	barrel
Bbls	barrels
Bcf	billion cubic feet
BOE	barrel of oil equivalent (6 Mcf = 1 BOE)
Bopd	Barrels of oil per day
GJ	Gigajoule
GJs/d	Gigajoules per day
Mbbls	thousands of barrels
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbls	millions of barrels
MMcf	million cubic feet
MMcf/d	million cubic feet per day
FNR	future net revenue
NGL	natural gas liquids
NPV	net present value

FORWARD-LOOKING STATEMENTS

This report contains certain forward-looking statements that involve substantial known and unknown risks and uncertainties, certain of which are beyond Petro-Reef's control, including: the impact of general economic conditions in Canada, the United States and worldwide; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; fluctuations in foreign exchange or interest rates; stock market volatility and market valuations of companies with respect to announced transactions and final valuations thereof; and obtaining required approvals of regulatory authorities.

Petro-Reef's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits, including the amount of proceeds, that Petro-Reef will derive therefrom.

PETRO-REEF RESOURCES LTD.

Highlights of Financial and Operations Results for Fiscal Years 2003 and 2002.

Financial	2003	2002	% Change
Crude oil and Natural Gas Revenue	$894,261	$643,712	38
Cash flow from operations	$244,486	$168,213	45
Cash flow from operations per share	$0.01	$0.01	-
Net loss from operations	$148,453	$126,498	17
Net loss per share	$0.01	$0.01	-
Capital Expenditures	$1,557,439	$872,447	79
Bank Loan	$1,150,000	0	-
Shareholder's equity	$4,289,534	$4,343,876	21
Common shares outstanding Weighted average	17,688,937	17,602,362	0.49
Operations			
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	6	4	50
Natural Gas (mcf/day)	409	470	-13
Total BOE/day	74	82	-10
Average Selling Price			
Crude Oil ($per Bbl)	43.21	40.12	8
Natural Gas ($per mcf)	6.66	4.04	65
NGL ($per Bbl)	44.14	40.80	8
Operations	**December 2003**	**December 2002**	**% Change**
Daily Average Production			
Crude Oil and NGLs (Bbls/day)	9	7	29
Natural Gas (mcf/day)	1,172	377	311
Total BOE/day	205	70	293
Average Selling Price			
Crude Oil ($/Bbl)	35.39	39.45	-10
NGL ($/Bbl)	20.12	37.72	-47
Natural Gas ($/mcf)	6.45	6.31	2

PETRO-REEF RESOURCES LTD.

PRESIDENT'S MESSAGE AND REVIEW OF ACTIVITY

Petro-Reef Resources Ltd. is a Calgary based crude oil and natural gas exploration and production company with producing properties in Alberta, Canada.

Petro-Reef Resources Ltd. had cash flow from crude oil and natural gas operations in 2003 of $244.486 compared to $168,213 in 2002. These values are net of royalties, Alberta Royalty Tax Credit, and after production, general and administrative, and interest expenses, but before depreciation and depletion, income tax, and future site restoration.

Production for 2003 was 27,180 barrels of oil equivalent. Production for 2002 was 28,849 barrels of oil equivalent. Note that natural gas is converted to a barrel of oil equivalent (BOE) using six thousand cubic feet equal to one BOE unless otherwise stated. This conversion conforms to the Canadian Securities Regulators National Instrument 51-101. A BOE is a very approximate comparative measure that could be misleading in some cases, particularly if used in isolation.

Ninety-seven point two percent (97.2%) of Petro-Reef's production in 2003 came from the two core properties. They are Peavey/Morinville with fifty-one percent (51.0%) and Alexander/Qui Barre with forty-seven point two percent (47.2%) of the production. The remaining two point eight percent (2.8%) comes from minor working interest and royalty properties.

In the Peavey/Morinville prospect area no new wells were drilled in 2003. The emphasis during 2003 and in 2004 was to develop production from several capped natural gas wells which either had not been tied-in for production or were candidates for re-completion in up-hole horizons which had previously tested or indicated by log analysis that they were capable of commercial production.

In the Alexander/Qui Barre prospect area one well was drilled in July of 2003. The well was drilled into the Devonian Wabamun formation. Petro-Reef has a forty-four percent working interest. The well was open-hole completed to total depth and encountered eighty-six feet of porosity. Test results from the open hole produced natural gas at rates of up to twenty-two million cubic feet per day. Infrastructure for production of the well – ie: pipelines and plant facilities were then constructed. Finally in mid November production testing began at a rate of about 1.9 cubic feet of natural gas per day with minor amounts of crude oil. By December 31, 2003 this well had produced, net to Petro-Reef, 6448 barrels of oil equivalent with only 128 barrels of crude oil, and had generated for Petro-Reef a net operating revenue of $184,800. For December 2003 the well produced about 134 barrels of oil equivalent per day in addition to production from other well of about 60 barrels of oil equivalent per day, net to Petro-Reef. Total production for 2003 net to Petro-Reef was 27,179.85 barrels of oil equivalent.

During December 2003 production rates declined such that by early January 2004 the natural gas production had dropped to about 1.35 million cubic feet per day with about twenty-five barrels of crude oil per day. It was determined that additional equipment and facilities were required to improve production. This took a period of six weeks in January and February 2004 during which time the well was not produced. In addition complications arose due to mechanical failures brought about by a spell of severe cold weather conditions. The well was placed back on production on February 22, 2004. Since then compression facilities have been added in order to be able to deliver the natural gas at pipeline pressure.

Plans for the Peavey/Morinville area are to continue with the process of adding additional production. The work in 2003 has added pipeline capability and has developed a central processing facility to handle more natural gas as required.

Plans for the Alexander/Qui Barre area are to drill as many as three development wells. The first development well has been licensed to a depth of 1,700 meters as a test into the Leduc formation. Tentative drilling date has been scheduled for late June/early July 2004. The locations for these wells were defined with the aid of an eight square mile 3D seismic program recorded in 2003, with excellent results.

The company continues to use the following exploration criteria on each prospect to assure high profitability and rate of return on capital investment:

1) Each exploration prospect must exhibit
    a) A minimum three hydrocarbon zone potential.
    b) Each zone must show the potential for:

        (i) 10:1 profit to capital risk ratio
        (ii) a minimum of 30% rate of return on capital invested.
        (iii) minimum life of 15 years.

2) The use of 2-D and 3-D seismic to identify and confirm potential drilling locations using state-of the-art technology.

On behalf of Petro-Reef and the board of directors, I would like to thank the shareholders for their continued support. We will continue to endeavor to meet and hopefully exceed your expectations in what has started as an exciting first part of fiscal year 2004.

Dated: May 7, 2004

Joseph Werner
President and
Chief Executive Officer

RESERVES REPORT

1) Reserves

As a result of more stringent reserve reporting rules and guidelines many oil and gas companies have had to report a major reduction in proven plus probable reserves. Petro-Reef's proven plus probable net reserves however, based on an independent engineering year-end evaluation, indicated an increase of fifteen percent (15%) to 461.6 MBOE from 402.0 MBOE in the previous year before 2003 production, and an increase of twenty-two percent (22%) after 2003 production.

Reserves were ninety-three percent (93%) natural gas and seven percent (7%) crude oil and NGLs. New reserve additions (after revisions) during fiscal year 2003 were 165.2 MBOE of which eighty-six percent (86%) was natural gas. The company's reserve replacement ratio was 6.1 to 1.

Of the total net reserves reported, Petro-Reef's reserves are fifty-two percent (52%) proved and forty-eight percent (48%) probable.

- Proven reserves – are reserves that can be estimated to be recoverable with a high degree of certainty.

- Probable reserves – are those reserves were recovery is less certain than with proven reserves. Under the definition, there is equal probability that actual remaining quantities recovered will be greater – or less – than the sum of the estimated proven plus probable reserves.

- Possible reserves – are less likely to be recoverable than probable reserves. The probability that remaining amounts recovered will exceed the sum of the estimated proved plus probable plus possible reserve is ten percent (10%).

Reserves reconciliation

The previous evaluation dated January 1, 2003 was prepared using definitions in accordance with National Policy 2-B. National Policy 2-B required probable reserves adjustments to account for risk associated with their ultimate recovery. Petro-Reef previously applied a recoverable risk factor of fifty percent (50%) in reporting it's probable reserves. Under new National Instrument 51-101 definitions, estimates are prepared such that there is a fifty percent (50%) chance of recovering at least the full proved plus probable reserves. The reserves reconciliation reflects current proved plus probable reserves as opposed to the January 1, 2003 Status Report which used proved plus fifty percent (50%) risk adjusted probable reserves. The January 1, 2004 report was prepared by Sproule Associates Limited.

2) Reserves Value

Using a ten percent (10%) NPV, the value of proved plus probable reserves has increased by twenty-one percent (21%) compared with last year's established reserves.

3) Reserve Life Index (as at January 1, 2004)

Based on established reserves and production volumes, Petro-Reef's reserve life index was 24.4 years at the end of 2003 compared with 30 years at the end of 2002 – a nineteen percent (19%) decrease. This is using National Instrument 51-101 for 2003 and National Policy 2-B for 2002. Petro-Reef's reserve life index (RLI) is an indication of the number of years it would take to deplete the Company's reserves. The RLI is obtained by dividing the year end reserves by the average daily production of oil, natural gas and natural gas liquids for a calendar year as estimated and determined by the independent reserves evaluator.

4) Evaluation Standards

This report has been prepared by Sproule Associates Limited using state-of-the-art geological and engineering knowledge and techniques. It has been prepared with the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). Finally, this report adheres in all material aspects to the "best practices" recommended in the COGE Handbook which are in accordance with principals and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101.

5) The Evaluation of the petroleum and natural gas

The Evaluation of the petroleum and natural gas reserves of Petro-Reef Resources Ltd. has been approved by the company's reserve committee and the board of directors.

6) Statement of Reserves Data

Following is a detailed report on the reserves and future net revenue in six parts:

Part 1	Date of Statement
Part 2	Disclosure of Reserves Data
Part 3	Pricing Assumptions
Part 4	Reconciliation's of changes in Reserves and Future Net Revenue
Part 5	Additional Data Relating to Reserves Data
Part 6	Other Oil and Gas Information

STATEMENT OF RESERVES DATA

AND OTHER OIL AND GAS INFORMATION

TABLE OF CONTENTS

PART 1	DATE OF STATEMENT
Item 1.1	Relevant Dates
PART 2	DISCLOSURE OF RESERVES DATA
Item 2.1	Reserves Data (Constant Prices and Costs)
Item 2.2	Reserves Data (Forecast Prices and Costs)
PART 3	PRICING ASSUMPTIONS
Item 3.1	Constant Prices Used in Estimates
Item 3.2	Forecast Prices Used in Estimates
PART 4	RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE
Item 4.1	Reserves Reconciliation
Item 4.2	Future Net Revenue Reconciliation
PART 5	ADDITIONAL INFORMATION RELATING TO RESERVES DATA
Item 5.1	Undeveloped Reserves
Item 5.2	Significant Factors or Uncertainties
Item 5.3	Future Development Costs
PART 6	OTHER OIL AND GAS INFORMATION
Item 6.1	Oil and Gas Properties and Wells
Item 6.2	Properties With No Attributed Reserves
Item 6.3	Forward Contracts
Item 6.4	Additional Information Concerning Abandonment and Reclamation Costs
Item 6.5	Tax Horizon
Item 6.6	Costs Incurred
Item 6.7	Exploration and Development Activities
Item 6.8	Production Estimates
Item 6.9	Production History

PART 1 DATE OF STATEMENT

1.1 Relevant Dates

1. Date the statement: April 30, 2004
2. Effective date: January 1, 2004
3. Preparation date: Between January and April 1, 2004.

PART 2 DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Constant Prices and Costs)

2.1.1 Reserves Gross and Net (Constant Prices and Costs)

Summary of Oil and Gas Reserves
as of January 1, 2004
Constant Prices and Costs

Reserves

	Light and Medium Oil		Natural Gas [1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved						
Developed Producing	13.9	11.7	1,019	925	3.0	2.7
Developed Non-Producing	4.7	4.2	225	192	4.6	3.1
Undeveloped	0.0	0.0	332	284	0.0	0.0
Total Proved	**18.7**	**15.9**	**1,576**	**1,401**	**7.6**	**5.8**
Probable	13.3	11.4	1,425	1,174	10.3	7.4
Total Proved Plus Probable	**32.0**	**27.2**	**3,001**	**2,575**	**17.9**	**13.2**

Note:

1) Includes solution gas.

2.1.2 Present Value of Future Net Revenue (Constant Prices and Costs)

Summary of Net Present Values of Future Net Revenue as of January 1, 2004 Constant Prices and Costs				
	Net Present Values of Future Net Revenue [1]			
	Before Income Taxes [2] Discounted at (% / Year)		After Income Taxes [2] Discounted at (% / Year)	
Reserves Category	**0 (M$)**	**10 (M$)**	**0 (M$)**	**10 (M$)**
Proved				
Developed Producing	4,492	3,440	4,054	3,122
Developed Non-Producing	1,153	950	735	601
Undeveloped	1,229	823	839	556
Total Proved	**6,873**	**5,212**	**5,628**	**4,279**
Probable	6,404	4,277	4,124	2,710
Total Proved Plus Probable	**13,277**	**9,490**	**9,752**	**6,990**

Notes:

1) NPV of FNR include all resource income:
   - Sale of oil, gas, by-product reserves
   - Processing third party reserves
   - Other income

2) Income Taxes
   - Includes all resource income
   - Apply appropriate income tax calculations
   - Include prior tax pools

2.1.3 Future Net Revenue (Constant Prices and Costs)

Total Future Net Revenue (Undiscounted) as of January 1, 2004 Constant Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	12,988	2,326	2,326	83	147	6,873	1,269	5,628
Total Proved Plus Probable	24,218	4,428	6,226	119	168	13,277	3,525	9,752

2.1.4 By Production Group-Future Net Revenue before Income Tax (Using Constant Prices and Costs – Using a discount rate of 10 percent).

Net Present Value of Future Net Revenue By Production Group as of January 1, 2004 Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10% Year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	318
	Natural Gas (including by-products but excluding solution gas from oil wells)	4,809
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	523
	Natural Gas (including by-products but excluding solution gas from oil wells)	8,881

2.2 Reserves Data (Forecast Prices and Costs)

2.2.1 Reserves Gross and Net (Forecast Prices and Costs)

Summary of Oil and Gas Reserves
as of January 1, 2004
Forecast Prices and Costs

Reserves

	Light and Medium Oil		Natural Gas [1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
Proved						
Developed Producing	13.9	11.7	973	893	2.8	2.6
Developed Non-Producing	4.7	4.2	225	192	4.6	3.2
Undeveloped	0.0	0.0	315	276	0.0	0.0
Total Proved	**18.7**	**15.9**	**1,513**	**1,362**	**7.4**	**5.7**
Probable	13.3	11.4	1,418	1,167	10.2	7.4
Total Proved Plus Probable	**32.0**	**27.3**	**2,931**	**2,527**	**17.6**	**13.1**

Note:

1) Includes solution gas.

2.2.2 Net Present Value of Future Net Revenue (Forecast Prices and Costs)

Summary of Net Present Values of
Future Net Revenue
as of January 1, 2004
Forecast Prices and Costs

	Net Present Values of Future Net Revenue [1]									
	Before Income Taxes [2] Discounted at (% / Year)					After Income Taxes [2] Discounted at (% / Year)				
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**
Proved										
Developed Producing	2,829	2,546	2,333	2,166	2,031	2,871	2,568	2,344	2,173	2,037
Developed Non-Producing	773	710	661	621	587	496	454	421	394	372
Undeveloped	736	608	515	445	390	491	405	341	294	257
Total Proved	**4,337**	**3,865**	**3,509**	**3,231**	**3,008**	**3,858**	**3,426**	**3,106**	**2,861**	**2,666**
Probable	4,109	3,395	2,926	2,592	2,339	2,662	2,190	1,880	1,659	1,492
Total Proved Plus	**8,446**	**7,260**	**6,435**	**5,823**	**5,347**	**6,520**	**5,616**	**4,985**	**4,520**	**4,158**
Probable										

Notes:

1) NPV of FNR include all resource income:
   - Sale of oil, gas, by-product reserves
   - Processing third party reserves
   - Other income

2) Income Taxes
   - Includes all resource income
   - Apply appropriate income tax calculations
   - Include prior tax pools

2.2.3 Future Net Revenue (Forecast Prices and Costs)

Total Future Net Revenue (Undiscounted) as of January 1, 2004 Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	9,978	1,738	3,668	85	150	4,337	504	3,833
Total Proved Plus	18,937	3,411	6,769	120	191	8,446	1,926	6,520
Probable								

2.2.4 By Production Group-Future Net Revenue before Income Tax (Using Forecast Prices and Costs – Using a discount rate of 10 percent).

Net Present Value of Future Net Revenue By Production Group As of January 1, 2004 Forecast Prices and Costs		
Reserves Category	**Production Group**	**Future Net Revenue Before Income Taxes (Discounted at 10% / Year) (M$)**
Proved Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	198
	Natural Gas (including by-products but excluding solution gas from oil wells)	3,225
Proved Plus Probable Reserves	**Light and Medium Crude Oil (including solution gas and other by-products)**	332
	Natural Gas (including by-products but excluding solution gas from oil wells)	6,017

PART 3 PRICING ASSUMPTIONS

3.1.1 Constant Prices Used in Estimates

Oil: Edmonton Par $40.68 per Bbl.
Natural Gas: Alberta AECO-C $6.88 per Mcf
Natural Gas By Products: Pentanes Plus $44.18 per Bbl.

3.2.1 Forecast Prices Used in Estimates

Summary of Pricing and Inflation Rate Assumptions as of January 1, 2004 Forecast Prices and Costs

	Oil			Natural Gas Liquids		
Year	WTI Cushing Oklahoma ($US / bbl)	Edmonton Par Price 40° API ($Cdn / bbl)	Natural Gas [1] Gas Prices ($Cdn / MMBtu)	Pentanes Plus FOB Field Gate ($Cdn / bbl)	Inflation Rate [2] (% / Yr)	Exchange Rate [3] ($US / $ Cdn)
Historical [4]						
2000	30.30	44.03	5.07	46.27	1.5	0.674
2001	25.94	39.06	6.23	42.46	2.0	0.646
2002	26.09	40.12	4.04	40.80	2.7	0.637
2003	31.13	43.21	6.66	44.14	2.5	0.716
Issuer's Weighted Average 2003 Prices						
	-	38.82	6.42	-	-	-
Forecast						
2004	29.63	37.99	6.04	38.91	1.5	0.75
2005	26.80	34.24	5.36	35.07	1.5	0.75
2006	25.76	32.87	4.80	33.67	1.5	0.75
2007	26.14	33.37	4.91	34.17	1.5	0.75
2008	26.53	33.87	4.98	34.69	1.5	0.75
Thereafter			Various Escalation Rates			

Notes

1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
2) Inflation rates for forecasting prices and costs.
3) Exchange rates used to generate the benchmark reference prices in this table.

4) Item 3.2 (1) (b) of Form 51-101F1 also requires disclosure of Petro-Reef's weighted average historical prices for the most recent financial year (2003, in this example).

Notes: Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Pricing assumptions were provided by a qualified reserves evaluator who is independent of Petro-Reef Resources Ltd.

The qualified reserves evaluator is Sproule Associates Limited.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

4.1 Reserves Reconciliation

	Oil			Non-Associated Gas			MBOE Basis		
	Proved Mstb	Probable Mstb	P+P Mstb	Proved MMcf	Probable MMcf	P+P MMcf	Proved MBOE	Probable MBOE	P+P MBOE
Starting Balance @ Dec 31, 2002	118.2	0.0	118.2	1573	130	1703	380.4	21.7	402.0
2003 Production	2.2	0.0	2.2	130	0	130	23.9	0.0	**23.9***
Discoveries	13.9	9.4	23.3	413	188	601	82.7	40.7	123.5
Acquisitions	0.0	0.0	0.0	0	250	250	0.0	41.7	41.7
Revisions	-111.4	3.9	-107.5	-418	863	445	-181.1	147.7	-33.3
Closing Balance @ Dec 31, 2003	18.7	13.3	32.0	1479	1394	2873	265.2	245.6	510.8

*** Note:**

Total production for fiscal year 2003 was 27.2 MBOE.
The difference between reported production and that reported above is due to production from properties which were not assigned reserves under the proved or probable categories by the independent reserves evaluator.

4.2 Future Net Revenue Reconciliation (Constant Prices & Costs)

For Proven Reserves Only @ 10% Discount of NPV

	Oil & Non-Associated Gas Proved Only $ @ 10% NPV
Starting Balance @ Dec 31, 2002	5931.3
2003 Production	-671.7 *
Acquisitions	0
Discoveries (1)	1606.0
Net Revisions (2)	-1653.6
Closing Balance Dec 31, 2003	5212.0

* The different dollar amount between the fiscal year production from the proved reserves of $671,700 and the net revenue from the company's properties of $620,800 is $50,900.
The $50,900 difference are operating expenses from properties which have not been assigned reserves.

Note (1) Discoveries of proved reserves were assigned by the independent reserves evaluator to two (2) wells in the Alexander Field.

Note (2) Net Revisions of $1,653,600 were due to the change in evaluation of reserves under national policy 51-101 versus policy 2B used in the previous year.

4.2.1 Additional changes were due to changes used in the Constant Price forecasts for December 31 in fiscal years 2002 and 2003 as follows:

		December 31, 2002 Price $	**December 31, 2003 Price $**
Oil : Edmonton Par		$ 35.66/stb	$40.68/stb
Natural Gas (AECO-C)		$ 5.71/Mcf	$6.88/Mcf
Natural Gas By Products:	Pentanes Plus	$44.18/bbl	$35.66/bbl
	Butanes	$37.73/bbl	
	Propane	$31.67/bbl	

4.2.2 The difference in future development costs of proven undeveloped reserves from Dec. 31, 2002 to Dec. 31, 2003 is as a result of:

a) development expenditures made during fiscal year 2003 and;
b) change in development cost of proven undeveloped reserves as of Dec. 31, 2003.

4.2.3 The net change in income taxes are due to expenditures on properties during fiscal year 2003.

The tax pools at December 31, 2003 are as follows:

	COGPE	CDE	CEE	Class 39 & 41	Class 8	Total	Successor
Closing balance	939,307	758,675	3,145,799	503,466	23,110	5,370,357	365,399

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

5.1.1 Proved Undeveloped Reserves

Proved Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production and meet the proved reserves classification. Total net capital expenditures for 2004 and 2005 are anticipated to be $50,000.

Total capital net to Petro-Reef remaining at the preparation date are:

4-19-56-24W4 : $38,300
15-25-56-25W4: $ 1,500

5.1.2 Probable Undeveloped Reserves

No probable undeveloped reserves were assigned by the independent qualified reserves evaluator, therefore no capital expenditures are anticipated. All the probable category reserves are probable developed.

5.2 Significant Factors or Uncertainties

There are no economic factors or significant uncertainties that affect particular components of the reserves data.

5.3 Future Development Costs

5.3.1 Development Costs of Future Net Revenue

Proved Reserves (Constant Prices and Costs)		Proved Reserves (Forecast Prices and Costs)		Proved Plus Probable Reserves (Forecast Prices and Costs)	
Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%
$83,000	$71,000	$85,000	$73,000	$120,000	$107,000

5.3.2 Development Costs of Future Net Revenue (by year)

a) Proved Reserves (Constant Prices and Costs)

2004	$50,000
2005	0
2006	0
2007	$30,000
2008	0

b) Proved Reserves (Forecast Prices and Costs)

2004	$50,000
2005	0
2006	0
2007	$31,000
2008	0

c) Proved Plus Probable Reserves (Forecast Prices and Costs)

2004	$86,000
2005	0
2006	0
2007	$31,000
2008	0

PART 6 OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

Petro-Reef's two main properties representing 97.3% of its net present value (for proved plus probable reserves using 10% discounted values – before income taxes) are located in Central Alberta.

6.1.1 Producing Versus Non-Producing Reserves

Following are properties to which reserves have been attributed and are capable of producing but which are not producing as of the effective date, the percentage of those reserves to the total reserves, and the percentage of those reserves that are non-producing as of the date of this statement.

a) (i) Alexander

Total Proved plus Probable Reserves

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
94.1	32.0	27.3	3717	1460	1449

(ii) Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2003)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
41.2	8.6	7.7	651	124	96
Percentage of Total Reserves Non-Producing	%	%		%	%
	26.9	28.2		8.5	6.6

(iii) Total Proved plus Probable Non-Producing Reserves (@ April 30, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
41.2	8.6	7.7		16	12
Percentage of Total Reserves Non-Producing	%	%		%	%
	26.9	28.2		1.1	0.8

*** Includes solution gas**

Note: Remaining non-producing reserves are non-operated properties.

b) Morinville

(i) Total Proved plus Probable Reserves

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	4121	1418	1221

(ii) Total Proved plus Probable Non-Producing Reserves (@ Dec. 31, 2003)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	2064	613	529
Percentage of Total Reserves Non-Producing	%	%		%	%
	0	0		43.2	43.3

(iii) Total Proved plus Probable Non-Producing Reserves (@ April 30, 2004)

CRUDE OIL			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
0	0	0	2022	516	437
	%	%		%	%
	0	0		36.4	35.8

*** Includes solution gas**

Note: Of the remaining non-producing reserves 100% are non-operated by Petro-Reef. It is anticipated that these reserves will be placed on stream between July and September of 2004 for a total capital cost net to Petro-Reef of $78,000. The capital costs will be paid out of company cash flow.

c) Other Properties

Other properties represent 2.7% of the total net present value (before income tax) with approximately 90% of those properties producing. The other properties are all non-operated.

6.1.2 Producing Versus Non-Producing Oil & Gas Wells:

Following is a list of oil and gas well (gross and net) which are producing and non-producing. All the oil and gaswells are in central Alberta Canada.

Production is as of the preparation date of April 30, 2004

	Oilwells		Gaswells	
	Gross	Net	Gross	Net
Producing	0	0	11	3.227
Non-Producing @ April 30, 2004	0	0	2	0.475

Note: Only wells which have reserves assigned by the qualified independent reserves evaluator have been reported.

6.2 Properties With No Attributed Reserves

6.2.1 Unproved Properties

a) Gross Area: 9273 acres
b) Net Area: 3625 acres
c) Location: Central Alberta
d) There are no work commitments required for fiscal year 2004.

6.2.2 The net area of unproved property which is expected to expire in fiscal year 2004 is 117 acres.

6.3 Forward Contracts

The Company is not bound by any agreement (including any transportation agreement) which would preclude it from fully realizing future market prices for oil or gas.

6.4 Additional Information Concerning Abandonment and Reclamation Costs.

a) Petro-Reef estimates abandonment and reclamation cost based on historical average costs for the area net of salvage value at $30,000 per well.

b) Future net wells for which such costs shall be incurred are:

(i) For Wells where reserves are assigned equals 4.177 net wells.
(ii) For Wells where no reserves are assigned equals 2.888 net wells.
Total net wells = 7.065

c) Undiscounted cost to the Company = $211,950 for reclamation and abandonment.

d) The qualified independent reserves evaluator has estimated $191,000 for abandonment and reclamation net to the Company before recovery of salvage value.
Therefore $20,950 was not deducted as abandonment and reclamation costs in estimating the future net revenue.

e) The company expects to pay $34,000 in the next three years for reclamation and abandonment.

6.5 Tax Horizon

The Company does not expect to be required to pay income taxes for its 2003 financial year. It is anticipated that taxes will become payable for fiscal year 2005.

6.6 Costs Incurred (for fiscal year 2003)

6.6.1 Cost for COGPE, CEE, and CDE

a) Property acquisition costs (COGPE) $ 68,768
b) Exploration costs (CEE) $1,316,129
c) Development costs (CDE) $167,632

6.7 Exploration and Development Activities

6.7.1 Wells for fiscal year 2003

Exploration wells	2
Development wells	0

6.7.2 Wells for fiscal year 2003

Gaswells	1
Oilwells	1
Dry Holes	0

6.8 Production Estimates

6.8.1 Production estimates for 2004 are:

a) Using Constant Prices and Costs

Oil	3,700 Bbl
Gas	314 MMCF
NGL	3,000 Bbl

b) Using Forecast Prices and Costs

Proved:	Oil	3,700 Bbl
	Gas	314 MMCF
	NGL	3,000 Bbl
Proved Plus Probable:	Oil	9,100 Bbl
	Gas	499 MMCF
	NGL	7,200 Bbl

6.8.2 Of the above referenced production 97.2% is represented by two properties:

a) Morinville: 51.0% of the production
b) Alexander: 46.2% of the production

6.9 Production History for fiscal year 2003

2003 PRODUCTION & REVENUE SUMMARY

Month	Production BOE / Day	Production BOE / Month	Price $ / BOE	Royalty Expenses $/BOE	Netback $/BOE	Gross Revenue $ After Royalties	Operating Expenses $	Cash*Flow $
JAN	46.67	1,446.67	45.39	5.45	27.11	53,229.33	14,010.20	39,219.13
FEB	58.15	1,628.14	52.13	7.46	35.80	74,662.17	16,382.34	58,279.83
MAR	63.40	1,965.54	44.46	6.94	34.14	84,186.09	17,076.10	67,109.99
3 Month Average	**56.07**	**1,680.12**	**47.33**	**6.62**	**32.35**	**70,692.53**	**15,822.88**	**54,869.65**
APR	52.76	1,582.68	38.89	5.78	22.50	54,996.44	19,390.41	35,606.03
MAY	43.67	1,353.92	37.78	4.25	22.34	48,747.98	18,498.43	30,249.55
JUN	44.17	1,325.16	36.27	5.28	15.40	45,894.97	25,484.93	20,410.04
3 Month Average	**46.87**	**1,420.59**	**37.65**	**5.10**	**20.08**	**49,879.80**	**21,124.59**	**28,755.21**
JUL	44.97	1,394.02	37.65	4.27	18.10	43,644.70	18,408.88	25,235.82
AUG	67.12	2,080.81	33.61	4.14	22.95	65,976.25	18,214.39	47,761.86
SEP	65.37	1,961.11	31.07	4.12	18.11	57,336.53	21,828.14	35,508.39
3 Month Average	**59.15**	**1,811.98**	**34.11**	**4.18**	**19.72**	**55,652.49**	**19,483.80**	**36,168.69**
OCT	74.73	2,316.69	33.33	4.26	21.91	66,148.42	15,397.16	50,751.26
NOV	137.03	4,110.79	31.74	3.03	19.64	117,622.65	36,883.94	80,738.71
DEC	194.01	6,014.33	33.13	5.99	26.64	197,646.92	37,436.46	160,210.46
3 Month Average	**135.26**	**4,147.27**	**32.73**	**4.43**	**22.73**	**127,139.33**	**29,905.85**	**97,233.48**
Average for 2003	74.34	2,264.99	37.43	5.02	23.95	75,841.04	21,584.28	54,256.76
Total for 2003	-	**27,179.85**	-	-	-	**910,092.45**	**259,011.38**	**651,081.07**

*Note: Cash flow on this production and revenue summary is before Alberta Royalty Tax Credit, general and administrative costs, interest expense, and before income tax.

PETRO-REEF RESOURCES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the audited financial statements and notes, contained in the annual report for 2003 and is based on information available to April 01, 2004.

Revenue fluctuated because of product price, and is apparent on the table of natural gas prices received by Petro-Reef for the last three years.

Capital expenditures somewhat parallel revenues and the resulting cash available.

Assets have shown a continuing annual increase.

There are no long-term financial liabilities and there have been no dividends declared.

Product Price for Natural Gas ($ per Gigajoule)
Years: 2001-2002-2003-2004

Month of:	Price Per GJ Year 2001	Price Per GJ Year 2002	Price Per GJ Year 2003	Price Per GJ Year 2004
January	10.3364	2.910568	6.643443	6.659749
February	7.438433	2.91909	8.516847	5.757239
March	7.324812	4.048778	8.081131	5.881507
Total Price per Quarter:	25.099645	9.878436	23.241421	18.298495
Average Price per Quarter:	8.366548333	3.292812	7.747140333	6.099498
April	7.04929	4.193984	6.432713	
May	5.560984	3.837456	6.497444	
June	4.442052	2.895572	6.272281	
Total Price per Quarter:	17.052326	10.927012	19.202438	0
Average Price per Quarter:	5.684108667	3.642337333	6.400812667	0
July	3.339614	2.030368	5.478141	
August	3.363118	2.922435	5.700614	
September	2.293413	3.81699	5.328396	
Total Price per Quarter:	8.996145	8.769793	16.507151	0
Average Price per Quarter:	2.998719	2.923264333	5.502383667	0
October	2.921621	5.126845	5.245812	
November	3.209359	5.119114	4.989099	
December	3.50061	5.740151	6.178671	
Total Price per Quarter:	9.63159	15.98611	16.413582	0
Average Price per Quarter:	3.21053	5.328703333	5.471194	0
Average Price for Year	$5.06	$3.80	$6.28	

Note: 1 gigajoule = 1.054615 thousand cubic feet

Selected Financial Information for the Company is shown in the follow ing table for three years with year ends of December 31.

	2003	2002	2001
FINANCIAL			
Crude Oil and Natural Gas Revenue net of royalties and ARTC	$894,261	$643,712	$815,592
Cash Flow from Operations	$244,486	$168,213	$463,284
Cash Flow from Operations per Share Basic and Diluted	$0.01	$0.01	$0.03
Net (Loss) Earnings from Operations	($148,453)	($126,498)	$108,063
Net (Loss) Earnings per Share, Basic and Diluted	($0.02)	($0.01)	$0.01
Capital Expenditures	$1,557,439	$872,447	$961,100
Total Assets	$8,093,157	$6,686,347	$6,410,979
Bank Loan	$1,150,000	-	-
Shareholder's Equity	$4,289,534	$4,343,876	$4,421,374

The following table summarizes the results of the eight most recently completed quarters.

Summary of Quarterly Results For The Last Eight Quarters				
		Oil & Gas Sales Net of Royalties And ARTC	**Net Earnings (Loss)**	**Basic and Diluted Earnings per share**
2002				
	Q1	$145,563	($47,389)	$-0.0027
	Q2	$157,540	($53,648)	$- 0.003
	Q3	$146,858	($64,745)	$ 0.003
	Q4	$193,751	($39,284)	$-0.002
Total		$643,712	($126,498)	
2003				
	Q1	$211,493	($5,643)	$0.0003
	Q2	$176,756	($21,322)	$ 0.001
	Q3	$119,614	($68,094)	$-0.004
	Q4	$386,398	($107,324)	$-0.006
Total		$894,261	($148,453)	

Note: The 2003 Q4 loss of $107,324 includes $94,111 of stock based compensation expense.

The results of Operations for 2001, 2002 and 2003 are set out in the following tables under three categories.

1) Land acquisitions
2) Petro-Reef operated drilling
3) Drilling where Petro-Reef is not the operator

Joint venture partnerships are involved in both the operated and non-operated drilling and accounts for the varying interests held by Petro-Reef.

1) LAND ACQUISITIONS - MINERALS ONLY & BEFORE RENTALS & SURFACE LEASES					
YEAR	PERIOD	GROSS ACRES	NET ACRES	COST (NET)	COMMENTS
2001	Q1	1250	639.3	$26,247.10	
	Q2	1975	803.5	$44,821.63	NOTE (1) Disposition $79,242.26
	Q3	654	484.9	$3,163.00	
	Q4	79	44.7	$12,541.86	
2001 (Total)		3958	1972.4	$86,773.59	
2002	Q1	1,813.30	827.1	$59,746.14	
	Q2	655	342.3	$11,460.99	NOTE (2) Disposition $65,000
	Q3	1,280	260.5	$41,612.26	
	Q4	1,386.70	610.1	$50,433.97	
2002 (Total)		5135	2,040.00	$163,253.36	
2003	Q1	0	0	$286.51	NOTE (3) Lease Service only
	Q2	160	70.4	$4,677.21	
	Q3	480	211.2	$26,592.55	
	Q4	640	281.6	$26,594.16	
2003 (Total)		1280	563.6	$58,150.43	

NOTE (1) In the second quarter of fiscal year 2001 the company sold @ 12% interest in a section at Youngstown for $79,242.26. This section was purchased by Petro-Reef for one ($1.00) dollar. Total expenditures for the year for land was $86,773.25 for a net expenditure of $7,530.99.

NOTE (2) In the second quarter of fiscal year 2002 the company sold @ 10% interest in section 29-56-25W4 for $65,000.00. Total expenditures for land for 2002 was $163,563.26 for a net expenditure of $98,263.36.

NOTE (3) Lease Service only costs refers to third party land company expenses.

2) DRILLING: WHERE PETRO-REEF IS OPERATOR								
YEAR	PERIOD	COMPLETED	COST	ON STREAM	COST	STATUS	PER % (W.I.)	PER % GORR
2001	Q1							
	Q2							
	Q3							
	Q4	05-25-56-25W4	$157,884			Capped Gaswell	39.00%	0.33%
2002	Q1			05-25-56-25W4	$141,900	Producing Gaswell	39.00%	0.33%
		10-30-56-27W4	$35,555			Capped Gaswell	35.13%	-
	Q2							
	Q3			10-30-56-27W4	$171,508	Producing Gaswell	35.13%	-
		6-15-56-27W4	$47,275			Capped Gaswell	75.00%	-
		08-01-56-27W4	$313,208			Standing Oilwell	44.00%	
	Q4	05-29-56-25W4	0			Dry & Abandoned	45.00%	-
				08-01-56-27W4	$262,663	Producing Oilwell	44.00%	-
2003	Q1							
	Q2							
	Q3							
		05-31-55-26W4	$460,710			Capped Gaswell	44.00%	-
	Q4			05-31-55-26W4	$176,761	Producing Gaswell	44.00%	-

NOTE (1) Reserves as determined by independent engineering appraisal at the end of each year that the well is drilled in.

2) DRILLING: WHERE PETRO-REEF IS OPERATOR (Continued)						
YEAR	PERIOD	FIRST MONTH PRODUCTION (BOE/D)	FIRST MONTH REVENUE (NET PER)	REVENUE 12/2003 (NET PER)	RESERVES (1) (NET PER)	COMMENTS
2001	Q1					
	Q2					
	Q3					
	Q4					
2002	Q1	72 boe/d	$20,632.63	$12,800.85	144.7 mmcf	
	Q2					
	Q3	95 boe/d	$42,435.61	$17,796.06	696.3 mmcf	Pump added January 2004
					175.8 mmcf	Capped, negotiating compression contract
						Farmout Well; no cost to PER
	Q4				0	
		6 boe/d	$5,397.90	$3,302.39	60,400 bbls	Well made signs of loading up with oil over the new year.
2003	Q1					
	Q2					
	Q3					
	Q4	134 boe/d	$131,108.53	$131,018.87	being evaluated	Froze off @ -62 degrees Celsius January 10, 2004.
						Repaired facility & ran pump-Well back on stream
						February 22, 2004.

3) DRILLING: WHERE PETRO-REEF IS NOT OPERATOR								
YEAR	PERIOD	COMPLETED	COST	ON STREAM	COST	STATUS	PER % (W.I.)	PER % GORR
2001	Q1							
	Q2	01-10-56-25W4	$92,484			Dry & Abandoned		
		07-21-56-27W4	0			Gaswell		15.50%
	Q3	16-23-56-25W4	$138,645	16-23-56-25W4	$32,633	Producing Gaswell	31.2750257%	0.066749229%
		07-26-56-25W4	$5,702			Capped Gaswell	2.0750257%	4.542747687%
		102/07-21-56-27W4	0			Dry & Abandoned		
	Q4			07-26-56-25W4	$4,309	Producing Gaswell	2.0750257%	4.542747687%
		08-22-56-25W4	$85,396			Dry & Abandoned	31.2750257%	0.066749229%
		15-25-56-25W4	$4,817			Capped Gaswell	1.2750257%	9.066749229%
2002	Q1							
	Q2	04-19-56-24W4	$280,825			Capped Gaswell	36.50%	
				07-21-56-27W4	0	Producing Gaswell		15.00%
		15-36-55-27W4	0			Standing Oilwell	21.094%	
	Q3			15-36-55-27W4	$25,914	Producing Oilwell	21.094%	
						Capped Gaswell		
	Q4							

3) DRILLING: WHERE PETRO-REEF IS NOT OPERATOR (Continued)						
YEAR	PERIOD	FIRST MONTH PRODUCTION (BOE/D)	FIRST MONTH REVENUE (NET PER)	REVENUE 12/2003 (NET PER)	RESERVES (NET PER)	COMMENTS
2001	Q1					
	Q2				0	
		10.5 boe/d	$8,995.23	$12,981.39		Farmout Well; no cost to PER
	Q3	5.5 boe/d	$1,872.90		7.8 mmcf	Suspended March 2002; Awaiting recompletion
						Farmout Well; no cost to PER
	Q4	2.9	$2,745.11	$72.24	48.2 mmcf	Will be recompleted in 2004
					56.8 mmcf	Waiting to be Tied-In
2002	Q1					
	Q2				124.6 mmcf	Awaiting Tie-In
		10.5 boe/d	$8,995.23	$11,978.82	363.1 mmcf	Farmout Well; no cost to PER
						Farmout Well; no cost to PER
	Q3	2.4 boe/d	$412.72	$1,601.76	37500 bbls	
					being evaluated	Waiting for Tie-in in Mid-March ground conditions permitting Oil zone suspended November 2003.
	Q4					

Note: There were no wells drilled in 2003 where Petro-Reef was not the operator.

In the coming year the company will continue to have a working capital deficit, however, the companies cash available for the year will continue to be positive.

The company expects to incur capital costs of approximately $960,000 in 2004.

The company is not nor does it expect to be in default of any of its obligations.

The company's short term requirements for cash are met by current cash flow from operations and bank financing. Long term cash requirements will depend on the success of the drilling program. Currently long term financing is done with bank financing and current cash flow from operations. Consideration for future financing will include increase in our bank financing, issuance of shares from treasury and additional farm outs.

The National Bank of Canada has made available to Petro-Reef two sources of financing; Credit Facility A is a revolving line of credit for two million dollars ($2,000,000) at prime plus one percent (1%); Credit Facility B is for acquisitions and development in the amount of five hundred thousand dollars ($500,000) at prime plus one and one-quarter percent ($1^{1/4}$ %).

Petro-Reef has no off-balance sheet arrangements.

There were no related party transactions consummated by Petro-Reef in 2003.

The fourth quarter of 2003 saw significant changes, in operating revenue as a result of increased production. This event was reported in a press release dated March 11, 2004, the text of which follows:

"In July 2003 Petro-Reef drilled a well into the Devonian Wabamun formation in its core area in Central Alberta. Petro-Reef has a forty-four percent working interest. The well was open- hole completed to total depth and encountered eighty-six feet of porosity. Test results from the open hole produced natural gas at rates of up to twenty-two million cubic feet per day. Infrastructure for production of the well – ie: pipelines and plant facilities were then constructed. Finally in mid November production testing began at a rate of about 1.9 million cubic feet of natural gas per day with minor amounts of crude oil. By December 31, 2003 this well had produced, net to Petro-Reef, 6448 barrels of oil equivalent with only 128 barrels of crude oil, and had generated for Petro-Reef a net operating revenue of $184,800. For December 2003 the well produced about 134 barrels of oil equivalent per day in addition to production from other wells of about 60 barrels of oil equivalent per day, net to Petro-Reef. Total production for 2003 net to Petro-Reef was 27,179.85 barrels of oil equivalent. The conversion of natural gas to barrels of oil equivalent is at a rate of 6,000 cubic feet of natural gas to one barrel of oil equivalent.

During December 2003 production rates declined such that by early January 2004 the natural gas production had dropped to about 1.35 million cubic feet per day with about twenty-five barrels of crude oil per day. To optimize production it was determined that additional equipment and facilities were required. To accomplish this the well was not produced for a period of six weeks in January and February 2004. In addition complications arose due to mechanical failures brought about by a spell of severe cold weather conditions. The well was placed back on production on February 22, 2004. The well is currently producing natural gas in the range of 1.5 million cubic feet per day (BTU adjusted) along with about twenty-five barrels of crude oil per day. It has been determined recently to add compression facilities in March 2004 in order to maintain and possibly increase production.

The well referred to is PER et al Alexander 05-31-055-26W4M. Spud date was 2003-07-08. Rig release date was 2003-07-19. It was drilled with Petro-Reef as operator on an un-promoted basis. Petro-Reef has a 44% working interest. Two industry participants have the remaining 56% working interest.

The capital required for drilling, equipping, pipeline, consultation and including the compression to be installed in March will be in the range of $714,300, net to Petro-Reef.

Prior to the production of the well the average daily production for the first ten months of 2003 was about fifty-six barrels of oil equivalent. The 05-31 alone in December 2003 contributed one hundred thirty-four barrels of oil equivalent, an increase of about 139%. For the same ten month period average net operating revenue after royalties and operating expenses was about $41,013. The 05-31 alone in December 2003 contributed $131,019, an increase of about 219%.

Production from the well is not considered to be stable at this time and may undoubtedly experience further fluctuations".

As the time of writing this report Petro-Reef is not considered any proposed acquisitions or dispositions outside the normal course of business. If, as and when a transaction is proposed, and finalized it shall be reported as required.

Changes in Accounting Policies Including Initial Adoption are described in note 2 of the audited financial statements as follows:

" **2) Change in accounting policies**

Full cost accounting guideline

Effective January 1, 2003, the company adopted a new Canadian accounting guideline relating to full cost accounting for oil and gas operations, as outlined in note 1.

Prior to adopting the new standard, the ceiling test limit on the aggregate carrying value of oil and gas property, plant and equipment was based on the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less the estimated future costs for administration, financing, asset retirement obligations and income taxes.

A property, plant and equipment ceiling test write down of approximately $850,000, net of income tax, as at December 31, 2003 would have been required had the new standard not been adopted.

Stock options

Effective January 1, 2003, the company prospectively adopted the new Canadian accounting standard with respect to stock based compensation. The standard requires that the fair value method of accounting be applied for stock options awarded to directors, officers and employees after January 1, 2003. Compensation expense is recorded over the vesting period using the estimated fair value of the option on the grant date. Consideration paid on the exercise of stock options is recorded as share capital".

To date Petro-Reef has not filed an Annual Information Form.

The following information regarding share capital is taken from Note 4 of the audited financial statements.
The authorized share capital of the company is comprised of an unlimited number of preferred shares and an unlimited number of common shares. Details of the changes in the company's issued share capital during 2003 and 2002 are as follows:

		2003		2002
	Number of shares	**Amount $**	**Number of shares**	**Amount $**
Common shares				
Balance – Beginning of year	17,688,937	4,743,176	17,588,937	4,694,176
Issued for the exercise of stock options	-		100,000	49,000
Balance – End of year	17,688,937	4,743,176	17,688,937	4,743,176

Earnings per common share are calculated using the weighted average number of common shares outstanding during the year of 17,688,937 (2002- 17,602,362).

The company has a stock option plan for directors, officers and key employees. The exercise price of each option equals the market price of the company's stock on the date of grant. Options are vested over three years and expire after a maximum exercise period of five years from the date of issuance. A summary of the status of the company's stock option plan as of December 31, 2003 and 2002 and changes during the year is presented below:

		2003		2002
	Shares	**Weighted-average Exercise price $**	**Shares**	**Weighted-average Exercise price $**
Outstanding-Beginning of year	1,150,000	0.67	1,250,000	0.66
Granted	960,000	0.40	-	-
Exercised	-	-	(100,000)	0.49
Expired	(800,000)	0.49	-	-
Options exercisable at year end	1,310,000	0.42	1,150,000	0.67

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

		Options outstanding		Options exercisable	
Range of Exercise price	**Number outstanding**	**Weighted – Average remaining contractual life**	**Weighted - average Exercise price ($/share)**	**Number exercisable**	**Weighted - average Exercise price ($/share)**
$0.30 - $0.49	1,310,000	3.4 years	0.42	670,000	0.45

Contributed surplus

	2003 $	2002 $
Balance – Beginning of year	-	-
Stock options granted	94,111	-
Balance – End of year	94,111	-

Compensation cost of $94,111 has been recognized for stock options granted after January 1, 2003. The fair value of options granted to employees and directors was estimated at the date of the grant using a Black-Scholes option pricing model with the following assumptions:

Volatility factor of expected market price	1.25
Weighted average risk-free interest rate	3.84%
Weighted average expected life in years	3
Weighted average expected annual dividends per share	-

Petro-Reef Resources Ltd.

Financial Statements
December 31, 2003 and 2002

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

March 23, 2004

Auditors' Report

To the Shareholders of
Petro-Reef Resources Ltd.

We have audited the balance sheets of **Petro-Reef Resources Ltd.** as at December 31, 2003 and 2002 and the statements of operations and deficit and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

PricewaterhouseCoopers refers to the Canadian firm of PricewaterhouseCoopers LLP and the other member firms of PricewaterhouseCoopers International Limited, each of which is a separate and independent legal entity.

Petro-Reef Resources Ltd.

Balance Sheets

As at December 31, 2003 and 2002

	2003 $	2002 $
Assets		
Current assets		
Cash and short-term investments	-	258,865
Accounts receivable	992,523	328,170
Prepaid expenses and deposits	6,977	18,595
	999,500	605,630
Property, plant and equipment (note 3)	7,093,657	6,080,717
	8,093,157	6,686,347
Liabilities		
Current liabilities		
Cheques drawn in excess of bank	409,474	-
Bank line of credit (note 6)	1,150,000	-
Accounts payable and accrued charges	1,647,684	1,500,335
	3,207,158	1,500,335
Future site restoration	50,575	39,346
Future income taxes (note 5)	545,890	802,790
	3,803,623	2,342,471
Shareholders' Equity		
Capital stock (note 4)	4,743,176	4,743,176
Contributed surplus (note 4)	94,111	-
Deficit	(547,753)	(399,300)
	4,289,534	4,343,876
	8,093,157	6,686,347

The accompanying notes are integral to the financial statements.

Approved by the Board of Directors

Director

Director

Petro-Reef Resources Ltd.

Statements of Operations and Deficit

For the years ended December 31, 2003 and 2002

	2003 $	2002 $
Revenue		
Oil and gas sales, net of royalties and ARTC	894,261	643,712
Interest income	-	1,647
	894,261	645,359
Expenses		
Production	266,312	174,425
General and administrative	342,680	284,453
Stock based compensation (notes 2 and 4)	94,111	-
Depletion, depreciation and site restoration	555,728	379,799
Interest expense	40,783	18,268
	1,299,614	856,945
Loss before the following	(405,353)	(211,586)
Future income tax recovery (note 5)	256,900	85,088
Net loss for the year	(148,453)	(126,498)
Deficit – Beginning of year	(399,300)	(272,802)
Deficit – End of year	(547,753)	(399,300)
Basic and diluted loss per common share	(0.01)	(0.01)

The accompanying notes are integral to the financial statements.

Petro-Reef Resources Ltd.

Statements of Cash Flows

For the years ended December 31, 2003 and 2002

	2003 $	2002 $
Cash provided by (used in)		
Operating activities		
Net loss for the year	(148,453)	(126,498)
Items not affecting working capital		
Depletion, depreciation and site restoration	555,728	379,799
Stock based compensation	94,111	-
Future income taxes	(256,900)	(85,088)
Cash flow from operations	244,486	168,213
Net change in non-cash operating working capital items (note 7)	(227,457)	431,945
	17,029	600,158
Financing activities		
Issuance of common shares	-	49,000
Bank line of credit	1,150,000	-
	1,150,000	49,000
Investing activities		
Expenditures on property, plant and equipment	(1,557,439)	(872,447)
Disposal of property, plant and equipment	-	65,000
Net change in non-cash investing working capital items (note 7)	(277,929)	145,820
	(1,835,368)	(661,627)
Change in cash and short-term investments during the year	(668,339)	(12,469)
Cash and short-term investments – Beginning of year	258,865	271,334
(Outstanding cheques) cash and short-term investments – End of year	(409,474)	258,865
Supplemental information		
Interest paid	40,783	18,268
Interest received	-	1,697

The accompanying notes are integral to the financial statements.

1 Accounting policies

These financial statements of Petro-Reef Resources Ltd. (the "company") have been prepared in accordance with accounting principles generally accepted in Canada. Management has made the necessary estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses in the preparation of the financial statements. Accordingly, actual results may differ from estimated amounts but management does not believe such differences will materially affect the company's financial position or results of operations.

The company has a working capital deficit of $2,207,658 at December 31, 2003 (2002 – $894,705). The company's ability to continue as a going concern is dependent upon the continued support of the company's creditors, which management expects will be received. Without such creditor support, the company's assets and liabilities may not be realized or discharged in the normal course, with the result that carrying amounts could be adjusted materially.

Significant accounting policies are summarized as follows:

Oil and gas operations

The company is engaged in the exploration for and production of oil and natural gas in Canada.

The company follows the full cost method of accounting for oil and gas operations whereby all costs related to the acquisition of, exploration for and development of oil and gas reserves are capitalized. Such costs include leasehold acquisition costs, geological and geophysical costs, lease rentals, drilling, plant and equipment costs and related overhead. Government incentives are credited to the cost of the oil and gas properties at the time the expenditures are incurred. Proceeds from the disposal of properties are applied as a reduction of the cost of the remaining assets with no gain or loss recognized, unless such a sale would result in a change of more than twenty percent in the depletion rate.

The company places a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the "ceiling test"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the fair value of proved and probable reserves, and the cost, less any impairment, of unproved properties that contain no probable reserves.

Depletion is computed using the unit-of-production method based on gross estimated proved oil and gas reserves (converted to equivalent units on the basis of estimated relative energy content). In determining the appropriate depletion rate, the company includes the net book value of its oil and gas properties, as well as the estimated future costs to be incurred in developing proved reserves and excludes the unimpaired cost attributable to unproved properties.

Estimated costs of future abandonment and restoration of well sites and associated facilities are amortized over the life of the properties on a unit-of-production basis.

Depreciation

Depreciation of furniture and fixtures is calculated using the declining balance method at an annual rate of 20%. Depreciation of computer equipment is calculated using the declining balance method at an annual rate of 30%.

Income taxes

The company follows the liability method of accounting for income taxes. Under this method, the company records future income taxes for the effect of any differences between the accounting and the income tax basis of an asset or liability using income tax rates substantially enacted on the balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in income in the period of the change.

Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids owned by the company are recognized when title passes from the company to its customers.

Earnings per share

The company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that any proceeds from the exercise of in-the-money stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

Joint ventures

Substantially all of the company's activities are conducted jointly with other industry partners and accordingly, these financial statements reflect only the company's proportionate interest in such activities.

2 Change in accounting policies

Full cost accounting guideline

Effective January 1, 2003, the company adopted a new Canadian accounting guideline relating to full cost accounting for oil and gas operations, as outlined in note 1.

Prior to adopting the new standard, the ceiling test limit on the aggregate carrying value of oil and gas property, plant and equipment was based on the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less the estimated future costs for administration, financing, asset retirement obligations and income taxes.

A property, plant and equipment ceiling test write down of approximately $850,000, net of income tax, as at December 31, 2003 would have been required had the new standard not been adopted.

Stock options

Effective January 1, 2003, the company prospectively adopted the new Canadian accounting standard with respect to stock based compensation. The standard requires that the fair value method of accounting be applied for stock options awarded to directors, officers and employees after January 1, 2003. Compensation expense is recorded over the vesting period using the estimated fair value of the option on the grant date. Consideration paid on the exercise of stock options is recorded as share capital. The calculation of the compensation expense is disclosed in note 4.

3 Property, plant and equipment

	2003		
	Cost $	Accumulated depletion and depreciation $	Net $
Petroleum and natural gas	9,962,248	2,881,652	7,080,596
Furniture and fixtures	35,777	22,716	13,061
	9,998,025	2,904,368	7,093,657

	2002		
	Cost **$**	**Accumulated depletion and depreciation** **$**	**Net** **$**
Petroleum and natural gas	8,406,140	2,341,362	6,064,778
Furniture and fixtures	34,447	18,508	15,939
	8,440,587	2,359,870	6,080,717

No interest or general and administrative expenses were capitalized during the year.

Unproven property costs of $244,131 (2002 – $294,575) have been excluded from capitalized costs subject to depletion.

The company performed a ceiling test calculation at December 31, 2003 in accordance with the policy described in note 1. The oil and gas future prices used in the calculation were based on the company's January 1, 2004 commodity price forecast which is consistent with the price forecast used by its independent reserve evaluators. These prices have been adjusted for commodity price differentials specific to the company. The following table summarizes the benchmark prices used in the ceiling test calculation.

Year	**WTI Oil ($US/bbl)**	**Foreign Exchange rate**	**Edmonton Light (crude oil) ($Cdn/bbl)**	**AECO Gas ($Cdn/bbl)**
2004	29.63	0.75	37.99	6.04
2005	26.80	0.75	34.24	5.36
2006	25.76	0.75	32.87	4.80
2007	26.14	0.75	33.37	4.91
2008	26.53	0.75	33.87	4.98
2009 – 2015	28.17	0.75	35.98	5.33
Escalate thereafter	1.5% per year		1.5% per year	1.5% per year

The ceiling test calculation did not result in any impairment write down at December 31, 2003.

4 Capital stock

The authorized share capital of the company is comprised of an unlimited number of preferred shares and an unlimited number of common shares. Details of the changes in the company's issued share capital during 2003 and 2002 are as follows:

	2003		2002	
	Number of shares	**Amount $**	**Number of shares**	**Amount $**
Common shares				
Balance – Beginning of year	17,688,937	4,743,176	17,588,937	4,694,176
Issued for the exercise of stock options	-	-	100,000	49,000
Balance – End of year	17,688,937	4,743,176	17,688,937	4,743,176

Earnings per common share are calculated using the weighted average number of common shares outstanding during the year of 17,688,937 (2002 – 17,602,362).

Stock options

The company has a stock option plan for directors, officers and key employees. The exercise price of each option equals the market price of the company's stock on the date of grant. Options are vested over three years and expire after a maximum exercise period of five years from the date of issuance. A summary of the status of the company's stock option plan as of December 31, 2003 and 2002 and changes during the year is presented below:

	2003		2002	
	Shares	**Weighted-average exercise price $**	**Shares**	**Weighted-average exercise price $**
Outstanding – Beginning of year	1,150,000	0.67	1,250,000	0.66
Granted	960,000	0.40	-	-
Exercised	-	-	(100,000)	0.49
Expired	(800,000)	0.49	-	-
Options exercisable at year end	1,310,000	0.42	1,150,000	0.67

The following table summarizes information about fixed stock options outstanding at December 31, 2003:

	Options outstanding			Options exercisable	
Range of Exercise price	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price ($/share)	Number exercisable	Weighted-average exercise price ($/share)
$0.30 – $0.49	1,310,000	3.4 years	0.42	670,000	0.45

Contributed surplus

	2003 $	2002 $
Balance – Beginning of year	-	-
Stock options granted	94,111	-
Balance – End of year	94,111	-

Compensation cost of $94,111 has been recognized for stock options granted after January 1, 2003.

The fair value of options granted to employees and directors was estimated at the date of the grant using a Black-Scholes option pricing model with the following assumptions:

Volatility factor of expected market price	1.25
Weighted average risk-free interest rate	3.84%
Weighted average expected life in years	3
Weighted average expected annual dividends per share	-

5 Income taxes

The following table summarizes the temporary differences which give rise to the future income tax liability at December 31:

	2003 $	2002 $
Future income tax liabilities		
Property, plant and equipment	607,808	941,214
Future income tax assets		
Site restoration	(17,838)	(16,572)
Share issue costs	-	(3,490)
Non-capital loss carryforwards	(44,080)	(118,362)
	545,890	802,790

At December 31, 2003, the company has successor tax pools of approximately $365,399 available for deduction from future taxable income. These successor pools have not been recognized for purposes of the future tax calculation due to the uncertainty as to whether sufficient revenue will be realized from the related properties to utilize the pools.

The income tax provision differs from the amount computed by applying the expected income tax rate of 40.62% (2002 – 42.24%) to earnings before taxes. The reasons for this difference are as follows:

	2003 $	2002 $
Loss before taxes	(405,353)	(211,586)
Expected tax rate	40.62%	42.24%
Expected tax expense at combined federal and provincial rates	(164,654)	(89,374)
Crown royalties and production taxes	11,625	7,542
Alberta royalty tax credit	(2,906)	(1,886)
Resource allowance	(27,620)	-
Stock based compensation	38,228	-
Decrease in future taxes due to tax rate reduction	(112,129)	(10,416)
Other	556	9,046
Income tax recovery	(256,900)	(85,088)

6 Bank line of credit

The company has a bank operating line of credit to a maximum of $2,000,000, bearing interest at prime plus 1% per annum, with an additional $500,000 available for acquisition financing or for development drilling, at an interest rate of prime plus 1.25%. At December 31, 2003, the outstanding balance under the line of credit was $1,150,000 (2002 – $nil).

The line of credit is secured by $5,000,000 floating charge debenture over all the company's assets with a negative pledge and undertaking to provide fixed charges on the company's major producing properties at the request of the bank. The credit facilities are repayable on demand, and are reviewed periodically by the bank, the next review being scheduled on May 1, 2004.

7 Cash flows

Changes in non-cash working capital:

	2003 $	2002 $
Operating activities		
Accounts receivable	(573,814)	59,171
Prepaid expenses and deposits	11,618	40,862
Accounts payable and accrued charges	334,739	331,912
	(227,457)	431,945
Investing activities		
Accounts receivable	(90,539)	49,732
Accounts payable and accrued charges	(187,390)	96,088
	(277,929)	145,820
	(505,386)	577,765

8 Commitments

The present office lease agreement expires on August 31, 2004. Future lease payments to the end of the lease term under the company's office lease will total $28,027.

9 Financial instruments

Financial instruments include bank indebtedness, accounts receivable, and accounts payable and accrued charges. At December 31, 2003, the fair market value of the financial instruments approximated their carrying value due to the short-term maturity of these instruments.

THREE YEAR REVIEW

	2003	2002	2001
FINANCIAL			
Crude Oil and Natural Gas Revenue Net of royalties and ARTC	$894,261	$643,712	$815,592
Cash Flow from Operations	$244,486	$168,213	$463,284
Cash Flow from Operations per Share	$0.01	$0.01	$0.03
Net (Loss) Earnings from Operations	($317,464)	($126,498)	$108,063
Net (Loss) Earnings per Share	($0.02)	($0.01)	$0.01
Capital Expenditures	$1,557,439	$872,447	$961,100
Total Assets	$8,093,157	$6,686,347	$6,410,979
Bank Loan	$1,150,000	-	-
Shareholder's Equity	$4,743,176	$4,743,176	$4,694,176
Common Shares Outstanding			
End of Period	17,688,937	17,688,937	17,588,937
Weighted Average			
- Basic	17,688,937	17,588,937	17,588,937
- Outstanding	17,688,937	17,602,362	17,588,937
OPERATIONS			
Average Production			
Crude Oil and NGLs (Bbls/day)	6	4	0.4
Natural Gas (Mcf/day)	409	470	519
Total BOE per day 6:1	74	82	87
Finding & Development Cost per BOE (1)	$18.00	$14.87	$7.67
Netbacks ($per BOE) (3)	$23.95	$15.48	$24.03
Reserve Replacement Ratio	3.2	1.8	4.3
Average Selling Price			
Crude Oil ($per BOE)	43.21	40.12	(5)
Natural Gas ($per BOE)	39.96	24.24	32.04 (4)
NGL ($per BOE)	44.14	40.80	-
Reserves (Proved plus Probable)			
Crude Oil and NGLs (Bbls)	40,400	103,400	8,900
Natural Gas (MMcf)	2,527	1,795	2,142
Total BOE	461,600	402,567	366,067
Present Value of Reserves (M$) (2)			
Undiscounted before Taxes at 15%	13,277	10,378	6,024
Discounted before Taxes at 10%	9,490	6,297	4,080
Established Reserve Life Index (P+P)	24.4 yrs	30 yrs	22 yrs
Proven Reserve Life Index	15.4 yrs	30 yrs	22 yrs

(1) After revisions due to policy 51-101.
(2) Using Constant Prices and Costs.
(3) Using 6 to 1 conversion.
(4) Includes NGL
(5) Crude Oil sales were non-operated and reported with total oil and gas sales combined.

PETRO-REEF RESOURCES LTD.
CORPORATE INFORMATION

DIRECTORS AND OFFICERS

Joseph Werner (1) (3)
Chief Executive Officer
President & Director
Calgary, Alberta

Theodore M. Donhuysen (2)
Vice-President Exploration and Production
Chief Operating Officer & Director
Calgary, Alberta

Robert N. Maertens-Poole (3) (4) (5)
Chief Financial Officer
Treasurer and Director
Calgary, Alberta

John Lagadin (2) (4) (5)
Director
Calgary, Alberta

Alan P. Hallman (1) (2) (4)
Director
Calgary, Alberta

Dennis K. Ulrich (1) (3) (5)
Director
Medicine Hat, Alberta

R. Greg Powers (6)
Corporate Secretary
Legal Counsel
Calgary, Alberta

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Executive Committee.
(4) Member of the Governance Committee.
(5) Member of the Compensation Committee.

Head Office
2020, 800 - 5th Avenue S.W.
Calgary, Alberta, Canada T2P 3T6
Telephone: (403) 265-6444
Facsimile: (403) 264-1348
E-Mail: petroreef@shawcable.com

Auditors
PricewaterhouseCoopers LLP
Chartered Accountants
3100 111 5th Avenue SW
Calgary, Alberta T2P 5L3

Bank
National Bank of Canada
600 407 8th Avenue SW
Calgary, Alberta T2P 1E5

Registrar and Transfer Agent
CIBC Mellon Trust Company
600 333 7th Avenue SW
Calgary, Alberta T2P 2Z1

Stock Listing
TSX Venture Exchange
Trading Symbol PER

(6) Baker & McKenzie
2600 255 5th Avenue SW
Calgary, Alberta T2P 3G6